MONITORING WELL CONSTRUCTION AND PLUGGING DETAILS

Elk Hills A1-A2 Storage Project

Injection Zone Monitoring Well, 335X-7R

Facility Information

Facility Name: Elk Hills A1-A2 Storage Project
335X-7R Injection Zone Monitoring Well

Facility Contact: Travis Hurst / Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well Location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Description of Change
Attachment G – CP Details_335X-7R	1	11/4/22	Original document, combines well construction, and plugging plan into monitoring well narrative document.

Introduction

CTV requires three monitoring wells for the Elk Hills A1-A2 Storage Project. CTV intends to repurpose two existing wells for monitoring of both the injection interval and one above zone monitoring. Figure 1 identifies the wells proposed for monitoring the storage project. This document describes the construction, recompletion, logging, testing, operating, and plugging plans for injection zone monitoring well 335X-7R.

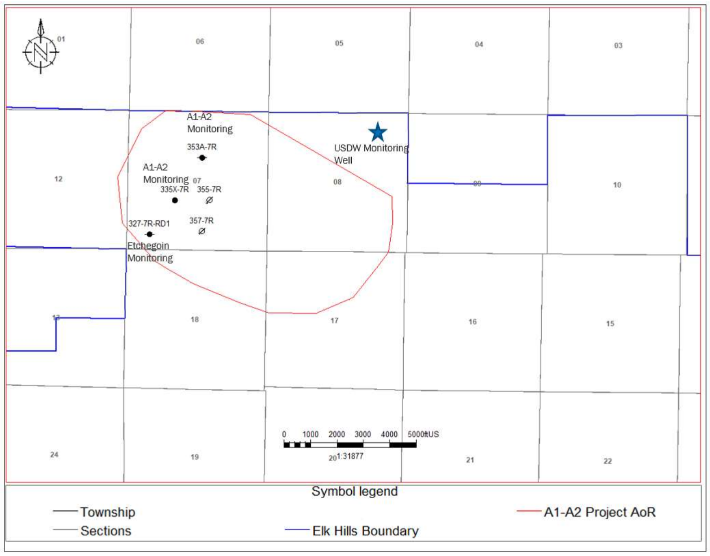

Figure 1: Map showing the location of injection wells and monitoring wells.

Monitoring well 335X-7R is an existing oil and gas production well that was drilled in 2014 and is currently inactive. CTV understands the well to be appropriately located, constructed, and in suitable mechanical condition to be re-used for monitoring this sequestration project. As specified in the Testing and Monitoring Plan, CTV plans to conduct an evaluation of mechanical integrity during pre-operational testing to ensure internal and external mechanical integrity.

The *Appendix: A1-A2 Injection and Monitoring Well Schematics* document provides casing diagram figures for all monitoring wells with construction specifications and anticipated completion details in graphical and/or tabular format.

Construction Details [40 CFR 146.82(a)(12)]

Injectate Migration Prevention and Protection of USDW

335X-7R was drilled in 2014, at which time there were no drilling and completion issues. The base of USDW is located at 854' MD & TVD in this well. The well was constructed in such a way as to prevent migration of fluids out of the injection zone and allow for monitoring required in the Testing and Monitoring Plan. Well construction details that support the protection of USDW and all strata overlying the injection zone are described by the following:

1. Surface Casing is set and cemented across the base of the USDW interval to surface such that, in combination with the 7" production casing, multiple casing strings protect shallow USDW-bearing zones from contacting fluids within the production tubing.

2. All casing strings were cemented in place using industry-proven recommended practices for slurry design and placement. Both surface casing and long string casing were cemented with returns to surface.
3. Cement bond logging was performed from the plugback depth of 7” casing around 9700’ to surface. The resulting CBL indicates presence of cement in the production casing annulus well above the base of Reef Ridge Shale confining layer.
4. Upper completion design (injection tubulars, packer, and wellhead) enables monitoring devices to be installed downhole, cased hole logs to be acquired, samples to be obtained, and Mechanical Integrity Testing (MIT) to be conducted.
5. Standard annular pressure tests (SAPT) demonstrate that the long string casing, tubing, packer, and wellhead have mechanical integrity. Internal MIT will be performed before the start of injection and any time the packer is reset to demonstrate isolation and integrity of primary barriers (tubing, packer, wellhead) and secondary barriers (casing, wellhead) for the protection of potential USDW.
6. Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment.
7. Realtime surface monitoring equipment with alarms and remote connectivity to a centralized facility provides continual awareness to potential anomalous pressure conditions.

The 335X-7R monitoring well was constructed using industry standards and recommended practices. Existing and future well materials comply with the following specifications.

1. API Spec 5CT / ISO 11960 – Specification for Casing and Tubing
2. API Spec 5CRA / ISO 13680 – Specification for Corrosion-Resistant Alloy Seamless Tubes for use as Casing, Tubing, and Coupling Stock
3. API Spec 10A / ISO 10426-1 – Cements and Materials for Cementing
4. API Spec 11D1 / ISO 14310 – Downhole Equipment – Packers and Bridge Plugs
5. API Spec 6A / ISO 10423 – Specification for Wellhead and Tree Equipment

Materials

Well materials utilized will be compatible with the mixture of CO_2 injectate and formation fluids to prevent corrosion in the well:

1. Tubing – corrosion-resistant alloy (CRA) consistent with accepted industry practices for corrosion mitigation based on mixture of formation fluids and injectate.
2. Wellhead – stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on mixture of formation fluids and injectate.
3. Packer – corrosion resistant alloy material or coating with hardened rubber elastomer element material.

4. Casing – the standard grade P-110 casing which is currently installed will be demonstrated to be compatible with the CO_2 injectate through corrosion coupon monitoring as discussed in the Testing and Monitoring document.
5. Cement – portland cement has been used extensively in enhanced oil recovery (EOR) producers for decades. Data acquired from existing wells supports that the cement is compatible with CO_2 when good cement bond between formation and casing exists within the Reef Ridge Shale.

Casing

The casing specifications in Table 1 are sufficient to meet the requirements of 40 CFR 146.86(b)(1)(iv) and to allow for the safe operation at expected bottomhole monitoring conditions.

The Monterey Formation temperature in A1-A2 is approximately 240 degrees Fahrenheit. These conditions are not extreme, and normal cementing and casing practices meet industry standards. Logging data to assess casing corrosion to be collected during pre-operational testing will be used to ensure the current condition of the casing will withstand the operational load associated with maintaining annular fluid and pressure.

Table 1: Casing Specifications for the 335X-7R Monitoring Well

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	25' - 65'	20	19.124	94	-	-	2.62	-	-
Surface	25' - 1993'	9.625	8.921	36	J-55	Long	2.62	3520	2020
Long-String	25' – 9790’	7	6.276	26	P-110	Long	2.62	9950	6230

Subsidence in the San Joaquin Valley is largely attributed to groundwater extraction related to agricultural activities that has been exacerbated by recent drought conditions. There is no groundwater extraction within the area of the Elk Hills Oil Field. As shown in Figure 2, the ten-year subsidence map demonstrates no appreciable subsidence in the AoR. Therefore, subsidence does not pose a risk to well integrity within the storage project.

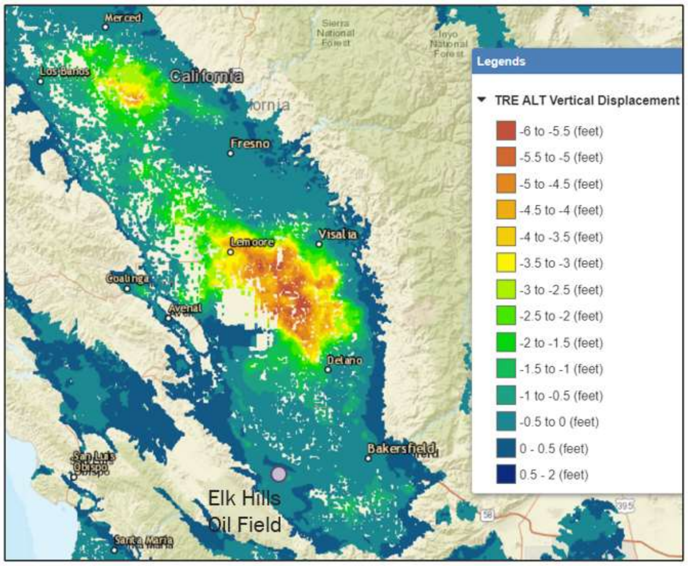

Figure 2: Subsistence in the Elk Hills Oil Field is -0.5 to 0 feet since 2015. Vertical displacement data for subsidence analysis is from the Sustainable Groundwater Management Act Data Viewer (https://sgma.water.ca.gov/).

Cement

Class C and Class G portland cements have been used to cement the well. Portland cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2. The 9-5/8" surface casing string was cemented using Class C portland cement with 56 cubic feet of cement returns to surface. The 7" casing string was cemented in place using Class G portland cement with 67 cubic feet of cement returns to surface. Subsequently, a CBL was run from ~9700' to surface and indicates the presence of annular cement that provides isolation between the Monterey and Reef Ridge formations.

Tubing and Packer

Table 2 provides monitoring tubing specifications as the well will be configured at the time of injection and supports the requirements of 40 CFR 146.86(c). The tubing and packer that are currently installed will be removed prior to injection. An appropriate grade of material will be installed based on the CO_2 injectate analysis performed during pre-operational testing.

Table 2. Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection Tubing	8707’	2.875	2.441	6.5	L-80 CRA	Premium	10,570	11,170

Table 3 provides specifications of a sealbore packer suitable to use in this application. The packer setting depth refers to the center of the element, and the packer inner diameter refers to the ID of the packer mandrel. The proposed packer setting depth is within a cemented interval of the 7” casing string.

Table 3. Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Sealbore Packer, CRA	8677’	30.3	23 - 32	6	2.37

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
100,000	8000	8000	6.466	6.184

Annular Fluid

4% KCl completion fluid treated with corrosion inhibitor and biocide will be circulated in the tubing/casing annulus at the time of tubing installation. The corrosion inhibitor and biocide additives will be compatible with the wellbore environment and bottomhole temperatures to prevent internal corrosion of the 7” casing and external corrosion of the tubing.

Alarms and Shut-off Devices

As described in the Testing and Monitoring Plan, monitoring wells will be configured with realtime downhole pressure, temperature, and annular pressure monitoring and alarms. Monitoring wells will have wellhead equipment sufficient to prevent leakage at surface. The wellhead tree will include redundant master valves and wing valves, and the valves will remain closed during normal injection operations. Safety valves or other automatic shut-off devices are not required for monitoring wells in general. The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Logging and Testing

Logging and testing data that was acquired during initial well construction is provided below. Data required pursuant to 40 CFR 146.87 that is not presented and has not been acquired will be acquired during pre-operational testing. Table 4 summarizes the pre-injection logging data and tests that CTV will acquire during the pre-operational testing and construction phase.

Table 4: Summary of Remaining Pre-Operational Logging and Testing

Data Collection Location(s)	Logging or Testing Activity	Spatial Coverage or Depth
335X-7R	Cement Bond Log	Along the 7" casing to surface
	Casing Inspection Log	Along the 7" casing to surface
	Internal MI: SAPT	Casing/tubing annulus above packer
	External MI (at least one of): Oxygen Activation Log Noise Log	Along the 7" casing to surface

Deviation Checks During Drilling

Deviation checks were acquired during drilling at varying frequency from ~184’ feet measured depth (MD) to bottom hole at 9839’ feet MD (Table 4).

Table 5: Deviation checks during drilling for the 335X-7R well.

MD	INC	AZI	TVD		MD	INC	AZI	TVD
0	0	0	0		6477	0.69	10.39	6475.9
184	0.1	54.1	184		6571	0.61	14.81	6569.9
274	0.4	82.8	274		6665	0.71	9.28	6663.9
553	1.3	45.2	553		6757	0.77	9.58	6755.9
843	1.1	42.7	842.9		6851	0.59	14.07	6849.9
1125	1	34.7	1124.9		6945	0.26	34.35	6943.9
1406	0.7	27.9	1405.8		7040	1.49	342.91	7038.9
1688	0.4	21.1	1687.8		7135	1.43	345.41	7133.8
1973	0.2	52.6	1972.8		7229	1.05	338.33	7227.8
2039	0.17	358.51	2038.8		7324	2.76	335.99	7322.7
2229	1.14	234.95	2228.8		7419	4.4	332.4	7417.6
2418	0.98	235.93	2417.8		7513	5.88	334.34	7511.2
2607	1.03	230.44	2606.7		7608	7.81	331.62	7605.5
2796	1	228.22	2795.7		7703	7.44	329.46	7699.7
2985	1.18	232.7	2984.7		7797	8.77	326.74	7792.7
3173	1.51	238.93	3172.6		7892	8.88	325.45	7886.6
3361	0.84	223.73	3360.6		7987	8.83	325.83	7980.5
3548	1.02	236.33	3547.6		8082	8.47	327.22	8074.4
3736	0.53	156.12	3735.5		8176	8.35	326.11	8167.4
3925	0.72	140.11	3924.5		8270	7.64	330.17	8260.5
4115	0.89	166.88	4114.5		8365	8.03	333.54	8354.6
4305	1.01	156.26	4304.5		8461	8.01	338.06	8449.6
4494	0.61	120.49	4493.5		8556	9.3	345.07	8543.5
4684	0.71	59.67	4683.5		8650	8.92	348.15	8636.4
4873	1.52	59.64	4872.4		8744	8.11	345.93	8729.3
5157	0.91	75.06	5156.4		8838	8.39	347.32	8822.4
5347	1.21	94.84	5346.3		8933	8.87	346.52	8916.3
5536	0.43	70.54	5535.3		9027	8.68	348.32	9009.2
5625	0.29	22.28	5624.3		9122	8.7	351.34	9103.1
5719	2.62	268.23	5718.3		9209	8.75	353.67	9189.1
5814	2.67	274.19	5813.2		9301	7.41	354.44	9280.2
5909	3.01	268.24	5908.1		9396	8.08	347.8	9374.3
6004	1.84	282.07	6003		9498	8.04	350.12	9475.3
6098	1.17	17.42	6096.9		9592	7.58	352.94	9568.4
6193	1.02	3.84	6191.9		9675	7.47	355.22	9650.7
6288	0.86	358.61	6286.9		9768	7.47	358.34	9742.9
6382	0.83	15.11	6380.9		9839	7.47	358.34	9813.3

Open Hole Log Analysis

Open hole wireline log data was acquired prior to installation of 7” long string casing. Figure 3 provides the results of these measurements that include spontaneous potential, natural gamma ray, and borehole caliper in track 1 (leftmost), resistivity in track 2 (second from left), and neutron porosity and bulk density in track 3.

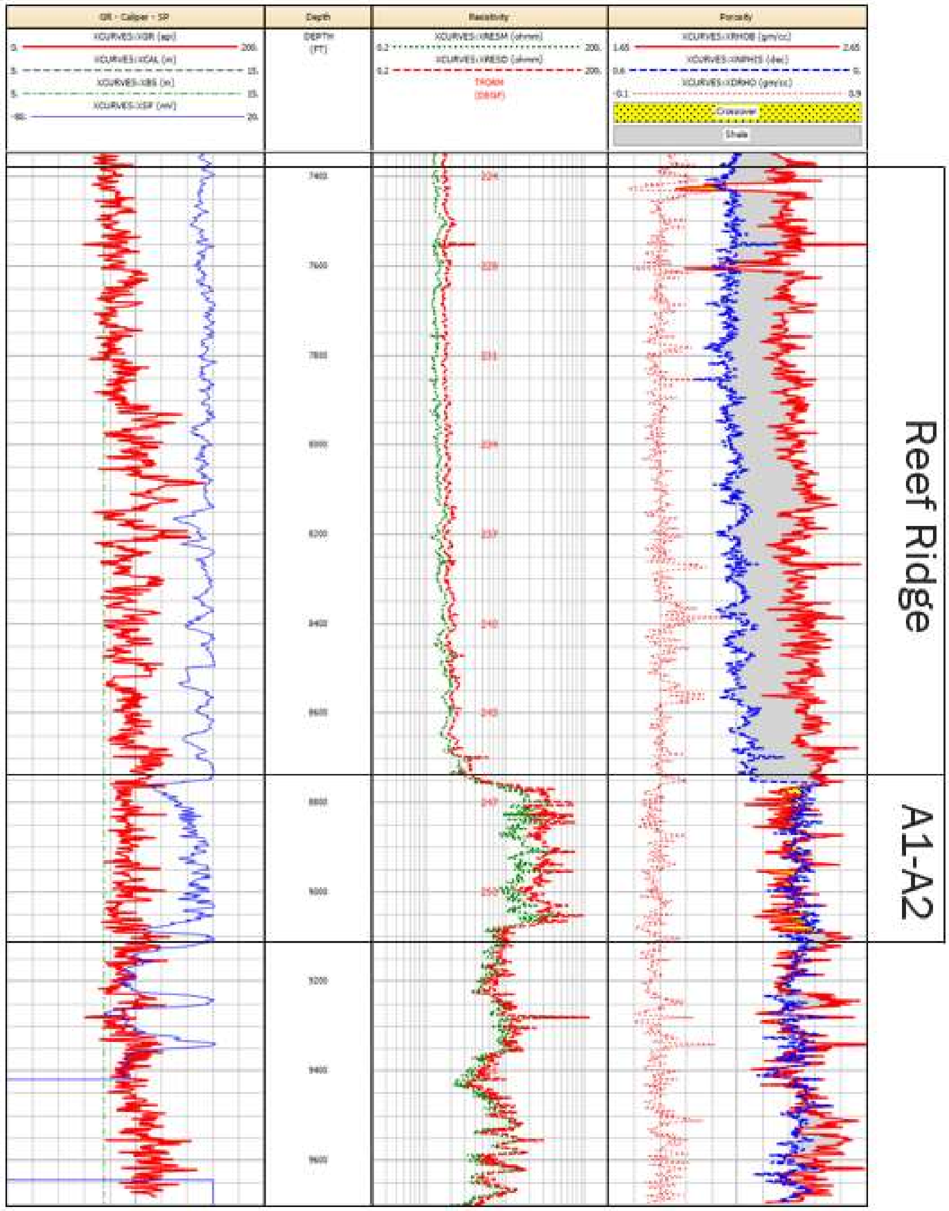

Figure 3: Open-hole well logs for 335X-7R before installation of long string for Reef Ridge Shale and Monterey Formations.

Cement Evaluation

The cement bond log amplitude and variable density log (VDL) acquired at the time of construction was logged across the entire 7” casing interval. Figure 4 shows good cement throughout the injection zone, with evidence of continuous cement throughout the confining layer and to surface. The Pre-Operational Testing plan document specifies additional cement evaluation logging to be performed across the entire 7” casing string during pre-operational testing.

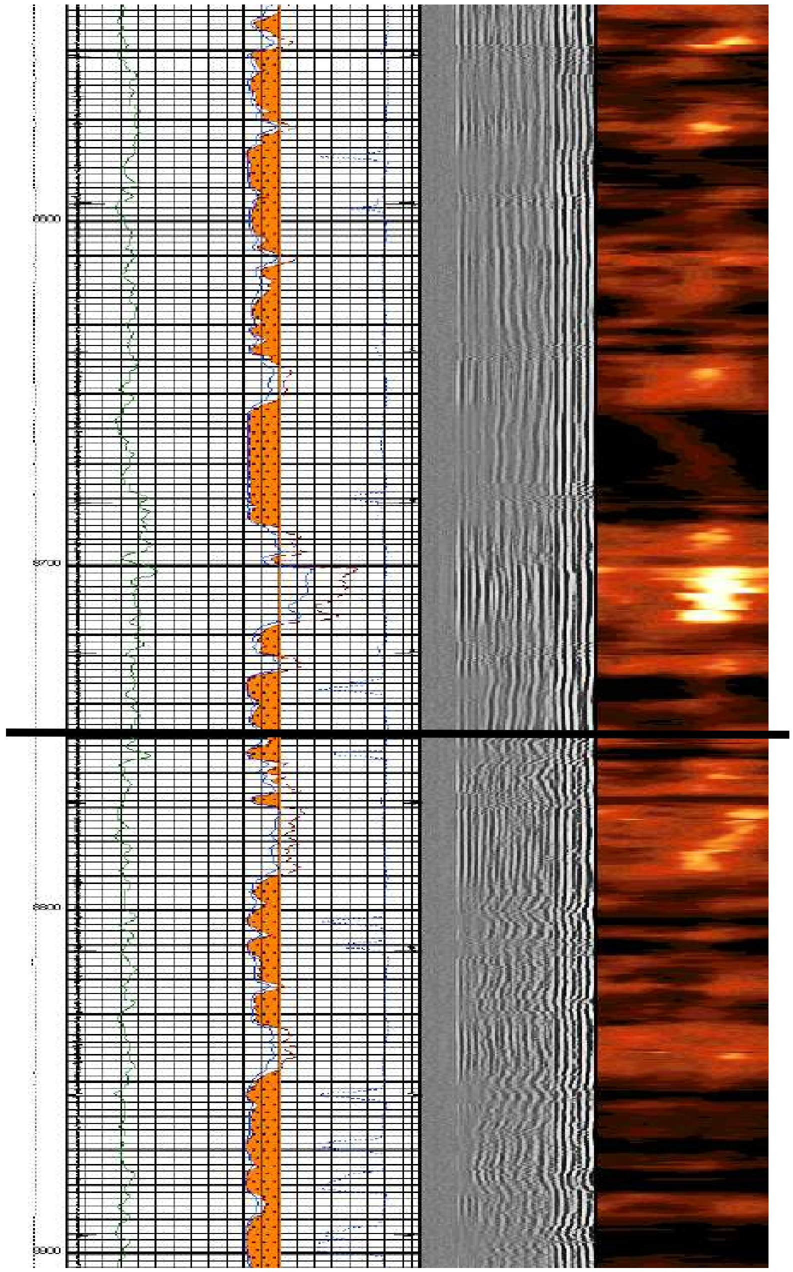

Figure 4: Cement bond log example for 335X-7R, after installation of long string casing. The Monterey Formation A1-A2 top is at 8,736 feet.

MIT – Internal: Standard Annular Pressure Test (SAPT)

SAPT is conducted to demonstrate that the tubing/packer/casing annulus system is presently not leaking and can provide a sufficient secondary barrier in the event of a tubing or packer leak. The SAPT test pressure and duration will be consistent with EPA-approved SAPT requirements and procedures. This testing will occur during installation of tubing string prior to injection, and this procedure is described in the Testing and Monitoring document.

MIT – External: Noise Log or Oxygen Activation Log

Noise logs and oxygen activation logs are approved forms of external mechanical by the EPA. An approved log would indicate tubing integrity and show no migration of injectate through the casing cement above the top perforation. An evaluation of external MIT using at least one of these approved methods will be performed during pre-operational testing and establish a baseline survey to support future external MIT evaluations during injection. These logging procedures are described in the Testing and Monitoring document.

Monitoring Well Plugging Plan

CTV's Monitoring Well Plugging Plan pursuant to 40 CFR 146.92 describes the process, materials, and methodology for monitoring well plugging.

Planned Tests or Measures to Determine Bottomhole Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottomhole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity test prior to plugging the monitoring well as required by 40 CFR 146.92(a). A temperature log or other approved external MIT will be run over the entire depth. The external MIT method will be a temperature log or other approved external MIT, and the procedure will be EPA-approved and consistent with procedures outlined in the Testing and Monitoring Plan. If a temperature log is run for external MIT, the temperature data will be evaluated for anomalies in the temperature profile by comparing to baseline temperature data acquired prior to injection of CO_2 and during the injection phase. If another approved external MIT method is used, it will be compared to baseline pre-injection data and/or other data acquired throughout the injection phase which the EPA has deemed acceptable.

Information on Plugs

CTV will use the materials and methods noted in Table 6 to plug the monitoring well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

A standard portland cement blend with specifications consistent with API Spec 10A will be designed with a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The properties of this cement blend will be at least equivalent to the properties of Class G portland cement, and the cement plug will provide an effective, long-term barrier to prevent migration of CO_2 into and within the wellbore. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2.

The wells will have this cement placed as detailed in Table 6, and all portions of the wellbore that are not plugged with cement will be filled with sufficiently weighted abandonment mud. The cement will be set in plug segments per CTV's standard procedures. Note that ground level corresponds to 25' MD due to the depth reference to the kelly bushing 25' above ground level during drilling.

Table 6: Plugging details

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4
Diameter of boring in which plug will be placed (in.)	6.276	6.276	6.276	6.276
Depth to bottom of tubing or drill pipe (ft)	9060	3003	1503	50
Sacks of cement to be used (each plug)	80	24	141	5
Slurry volume to be pumped (ft^3)	92	28	162	6
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	8634	2878	754	25
Bottom of plug (ft)	9060	3003	1503	50
Type of cement or other material	Class G Portland	Class G Portland	Class G Portland	Class G Portland
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced Plug, Retainer, or Coiled-Tubing Plug			

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Monitoring Well Plugging Plan, if applicable.

Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method may vary depending on the type of service equipment used. For instance, a maintenance rig may place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.

2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore and (2) that there is no CO_2 in the wellbore. If CO_2 were present in the wellbore, it would migrate to surface due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.

3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100' inside of the cement plug and is pulled up hole while cementing operations continue.

5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up hole while operations are paused to wait on cement.

6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.

7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up hole to the base of the next plug.

8. This process, beginning with step 4, is repeated for each cement plug until cement is placed to surface.

CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.
- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has >10,000 mg/L TDS):
  - If there is cement behind the casing across the base of USDW (if present), a 100-foot cement plug shall be placed inside the casing across the interface.

- If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits. In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.

- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.